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Published in:
Proceedings from 10th Dubrovnik Conference on Sustainable Development of Energy, Water and Environment Systems

Publication date:
2015

Document Version
Accepted author manuscript, peer reviewed version

Impact of Energy Transition in Germany on the Nordic Power Market – Blessing or Curse?

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Abstract

The European energy policy emphasizes the establishment of EU-wide internal energy markets as a reliable solution in increasing the security of supply, optimal use of internal energy resources, and improved economic competitiveness. With respect to the power sector, the EU's strategy is to further integrate and harmonize regional markets towards a pan-European power market with a single pricing algorithm. The impacts of such power market couplings on the interconnected countries are complex, which concerns market participants in different levels, from consumers and producers to grid operators, for example. The Nordic power market together with three other cross-border power exchanges launched the North-Western Europe (NWE) day-ahead price coupling project in 2014, which further bundles electricity prices in the Nordics with continental Europe, including Germany. The recent dramatic growth in the installed capacity of variable renewable energy (VRE) in Germany (Energiewende), has offered new opportunities and challenges that may affect the connected power markets, including the Nordic. The high-level hydro storage capacity in the Nordics is deemed a solution for balancing the electricity from VRE, leading to various plans for expanding the interconnectors to continental Europe. For example, a new transmission line (NordLink) between Norway and Germany is to be built by 2018 which increases the trade possibilities by 1400 MWh/h. The detailed analysis of the impacts of energy transitions in such interconnected countries calls for a market-based multi-region energy system model. In this respect, this contribution analyses the impact of further VRE in Germany on the Nordic countries by proposing a new integrated energy system, power market model of the region. The results reveal the market-economic impact of such market couplings on the Nordic consumers, power producers, and the grid owners.

Keywords

Cross-border energy system model, energy planning, market coupling, northern-west Europe (NWE) power market, optimization, power market model.

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Nomenclature

Abbreviations

CHP	combined heat and power
DH	district heating
ETM	European Target Model (for electricity market integration)
ESM	energy system model (referring to one region/country)
HDD	heating degree days
multi-ESM	multi-region energy system model (networked)
NWE	Northern-West Europe (power market)
PES	primary energy supply
PCR	price coupling of regions
RES	renewable energy source
TSO	transmission system operator
VRE	variable renewable energy

Symbols

D	power demand curve (price dependant)
e	power exchange
d	power demand
p	price of electricity
q	heat demand
S	power supply curve (price dependant)
s	power supply
T^{max}	maximum transmission capacity
t	heat supply

Superscripts		**Subscripts**	
dh	district heating	i (j,k)	price areas
os	onsite (energy production)	h	hour
el	electricity		

1. Introduction

The EU's strategy is to integrate national/regional energy markets across the EU as a solution for enhancing the security of supply, optimal use of shared resources, and achieving harmonized markets with competitive prices for consumers. In this respect, the integration of wholesale power markets will enhance the efficient use of power production capacity across national borders by optimal allocation of cross-border transmission capacity [1]. The expansion of power markets to wider geographical areas with various patterns of power supply and consumption is also deemed a flexibility measure to facilitate high-level integration of variable renewable energy (VRE) [2] – an important step towards EU energy and environmental targets.

In 2014, the Nordic power market exchange (Nord Pool Spot) together with three other power exchanges and 13 TSOs launched the North-Western Europe (NWE) day-ahead price coupling project. Therefore, a common day-ahead power price calculation algorithm is used based on the Price Coupling of Regions (PCR) solution [3]. NWE project coupled the day-ahead power markets across Central Western Europe (CWE), Great Britain, the Nordic countries, the Baltics, and the SwePol link (between Sweden and Poland). All interconnection lines within and between the participating countries will be optimally utilized through implicit auctioning.

The Nordic power market is connected to continental Europe through several links between: West Denmark and Germany, East Denmark and Germany, Sweden and Germany, Sweden and Poland, and Norway and the Netherlands. The large volume of hydro reservoirs in the Nordic region (mainly in Norway and Sweden) is considered a reliable solution for balancing the VRE in the continental EU [4]. This has led to further plans to expand the Nordic-Europe interconnection capacity, for example, between Norway and the UK, and between Norway and Germany [5]. The recent dramatic growth in the installed capacity of VRE in Germany as a result of the Energy Transition (*Energiewende*) has introduced new opportunities and challenges that may affect the connected markets. The increased fluctuations in power flow and the associated congestion will lead to further considerations in transmission planning and reserve capacity [6]. Higher price volatility [7,8] and greater needs for power balancing [9] are among the other implications of Germany's Energy Transition that can influence the coupled markets, including the Nordic power market.

Different studies have addressed the impact of market coupling between the Nordic power market and Europe, particularly between Norway and Germany. Jaehnert and Doorman [10] employ an operation optimization model to simulate the state of NWE power system in 2010 and 2020. They consider the case of market couplings by nearly doubling of interconnection capacity between the Nordic region and continental Europe to monitor the possibility of balancing VRE with the Norway's hydro power. They conclude that market coupling will result in higher price volatility in Norway, greater power exchange within the areas, and lower operation of thermal power plants. Farahmand et al. [11] assesses the challenges related to offshore wind power production variability in the North and Baltic Seas. They determine the transmission grid required for harvesting wind and to enable the optimal use of hydropower flexibility in a long-term cost-benefit analysis. In addition to an explicit offshore grid, they consider the power flow equations to study the possibility of loop flows. Doorman and Frøystad [12] examine the economic impact of an HVDC line between Norway and Great Britain, highlighting an increase in social welfare in different case studies, depending on the market conditions. In the abovementioned and other similar studies [13-15], the impact of market couplings and transmission expansions are investigated primarily based on power market models, focusing merely on the power sector (power production mix, hydropower reservoirs, transmission

networks, etc.). However, the capability of energy systems in absorbing VRE is not limited to the power sector.

The heat and power sectors are already interconnected in most of the Nordic countries, through combined heat and power (CHP) production, direct electric heating (or electric boilers), and heat pumps. In 2013, CHP plants supplied one-third of domestic power production in Finland [16]. Furthermore, 70% of the district heating (DH) demand is fulfilled by heat production from CHP plants. Many small and regional CHP plants are operated based on the respective heat demand. These plants are shut down during the summertime, which leads to the loss of the respective power supply. The situation in Denmark is even more intensive: two-third of electricity and DH production originated from CHP plants in 2012 [17]. This interlinkage of heat and power systems is, in some cases, backed with thermal energy storage, providing a buffer for unbundling of the instantaneous supply/demand of heat and electricity. In many future RES scenarios developed for the Nordic region, it is expected that the electrification of the heat sector [18-22] (as well as electric transportation [23]) will grow in importance as a flexibility solution for the large-scale integration of VRE. Accordingly, the future energy systems witness increasingly integrated heat, power, and transport sectors (the integration of other sectors, e.g., water desalination is also proposed [24]). The highly integrated energy systems and their role in achieving smart energy systems have been discussed in a number of publications, e.g. [25,26].

Therefore, different sectors of an energy system will be further linked to the power sector in the future, and consequently to the cross-border exchange of electricity in an EU-wide expanded grid. Traditional energy system models with focus on one country at a time and/or existing power market models based on a node-and-arc modelling approach might not be sufficiently capable to represent a group of networked energy systems. The study of such highly-interconnected energy systems calls for a new modelling paradigm that would be able to analyse both: (i) national-level energy system models (with possible integration of different sectors inside a region), as well as (ii) power exchange possibilities among interconnected power systems based on the governing market rules, pricing mechanism, network topology and transmission limitations. This study aims to contribute in this respect by proposing a new energy system model combined with a power market module. This paves the way in creating a so-called *complex energy system* model, comprising agent-based computational economics, simulation-based bottom-up model, and application of network theory (see Bale et al. [27]). Such a model is capable to compare the flexibility solutions inside a region (e.g., energy storage solutions inside a country) with the possibility of cross-border power exchange for balancing the VRE, for example.

In this contribution, we examine the impact of the Energy Transition in Germany on the Nordic power market, by proposing a new interconnected energy system of the region. We investigate this impact on all the Nordic countries (i.e., Norway, Denmark, Sweden, and Finland), which is not yet discussed in this format in the reviewed literature. The aim is to monitor how the dynamics of power and heat sectors (and in the future electrified transport) in the Nordic region would react on the future changes in power trade with Germany. Accordingly, we present a detailed energy system model of each Nordic country including heat, power, and transport sectors. Then, we examine the interconnection of these countries for power exchange through a common power market model (based on the Nord Pool Spot principles), coupled with the other external markets (within the NWE market and with Russia), given the cross-border power transmission capacities. Finally, the future prospective scenarios for power exchange with Germany are analysed and the impact on the Nordic region is examined. The remaining part of this study is structured as follows. In Section 2, we describe the methodology applied in this

study in more details. We present the benchmark energy system model of the Nordic region in 2013 followed by calibration and validation of the model in this Section. Section 3 summarizes the input data and assumptions, as well as the definition of future VRE scenarios. Section 4 presents the results and the associated discussion, followed by concluding remarks in Section 5.

2. Methodology

2.1. Market-Based Multi-Region Energy System Model

International or multi-regional energy models are suitable tools to inform energy planning when dealing with interdependences in energy policies of a group of countries/regions. From existing tools, MESSAGE [28] (long-term systems engineering optimization model), WILMAR [29] (short-term stochastic model), Balmorel [30] (partial equilibrium energy system model), and OseMOSYS [31] offer capabilities for the analysis of multi-region energy systems. The abovementioned models and other multi-regional energy system tools have capabilities and limitations that make them applicable for specific tasks and analyses (see [32] and [33]). A desirable model should be a flexible, expandable, and convenient platform for performing different studies, including short-term or long-term planning, deterministic or stochastic analysis, aggregate or GIS-based analysis, etc.

The multi-region energy system model (hereafter called *multi-ESM*) proposed in this study can be employed to simultaneously model a network of interconnected individual energy system models (ESMs). Hence, a multi-ESM has three distinguishable characteristics: (i) several ESMs with adequate details inside each ESM (e.g., one country), (ii) a network of energy carriers connecting the individual ESMs (e.g., cross-area power transmission network), and (iii) a common exchange platform which governs the exchange of energy between the individual ESMs (e.g., a power market). Pfenninger et al [34] categorizes energy models as energy system optimization models, energy system simulation models, power system and electricity market models, and qualitative and mixed-method models. In this regard, the model presented in this study is a combination of energy system simulation (for individual ESMs) and power market optimization model. As suggested by Dodds et al [35], the characteristics that distinguish energy system models from each other can be sorted as the model's paradigm and equations, spatial and temporal dimensions, model's structure or topology, model's constraints and boundaries, and required parametric data. From this perspective, the model proposed in this study is primarily a short-term model, with time resolution of one hour for each simulation run, and accepts the input data for modelling one day (24 h) up to one year (8760 h) time horizon at a time. Modelling of longer time periods is also possible, provided that the input time series would be adequately input to the model.

The model is built on MATLAB which incorporates built-in tools for data analysis, statistical analysis, optimization, geographical information system (GIS) -based studies, and uncertainty analysis. MATLAB can also be employed as a common, already-experienced communication platform between different experts working on the model, from power system analysers to statisticians. Figure 1 demonstrates the main components of a multi-ESM. The multi-ESM can be connected to other external multi-ESMs or individual ESMs as well (showed by dashed arrows). It should be noted that a multi-ESM model is different from multi energy carrier modelling, which mainly addresses the optimization of energy flow among several nodes [36,37]. For instance, in a multi energy carrier network suggested by Geidl and Andersson [38], the flow of power, gas, and DH is optimized for several interconnected hubs. However, they

consider the cost of the energy carrier independent from the other hub's, which does not address the countries connected to a common power market.

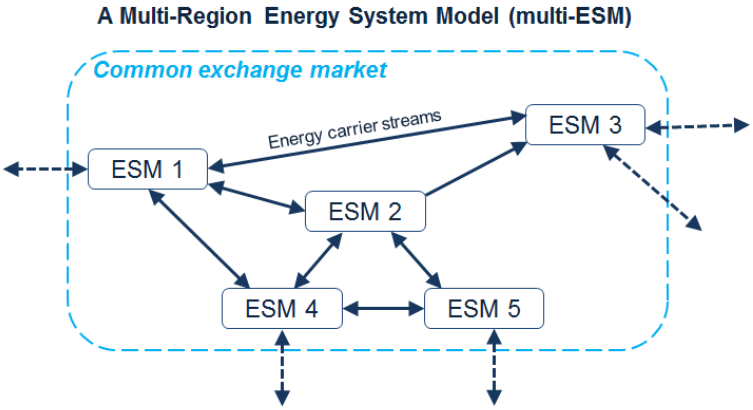


Figure 1. The main components of a multi-region energy system model (multi-ESM), including individual ESMs, the energy network among them, and the common energy exchange platform

In the model presented in this study, the network topology and the interconnections between the regions can be defined based on each case study. The network can be a DH network, power transmission network, or any other network of energy carriers. In the future work, other networks with significant influence on the energy system can be added to the model, such as information network for controlling the energy demand through smart metering. In this study, the term *network* refers to power transmission network between ESMs. Figure 2 illustrates the schematic representation of the main steps in the modelling of a multi-ESM, including the analytical approaches employed in each step. The individual ESMs are interconnected through a power market module (PMM) which clears the area prices of electricity in each bidding area[1].

The creation and analysis of a multi-ESM comprises of four distinctive steps that are coordinated through one single interface. MATLAB as the common interface is responsible for computational analyses, as well as communicating input-outputs among different steps. Therefore, all the input data, required computations, and the outcome are coordinated and communicated through one single package. Due to the flexibility of MATLAB, the modeller can adjust the modules in different case studies based on their particular needs. For example, while one researcher might be interested in the details of transmission network topology and the optimal power flow, the other would analyze the DH network and its customers in more details. The four main steps of the modelling and analysis are further introduced in this Section.

2.1.1. Input Data (Database)

To create the multi-ESM of the Nordic countries, first, we develop a benchmark model for the calendar year 2013, for which all the recorded data and statistics are available. The hourly distribution of power demand in each region for the reference year, as well as network transmission capacities are obtained from [39]. Then, the data of the power production mix is collected from ENTSO-E (The European Network of Transmission System Operators for Electricity) [40], and in more details from the Platts Database [41]. The techno-economic data related to CHP plants, heat production plants, fuels, and emission factors are based on the

[1] In this study, the term *region* refers to an energy system with distinguishable heat and power sector, corresponding to each Nordic country. The term *area* represents the (Nord Pool) biding areas, i.e., power market segments that might have different prices of electricity due to transmission bottlenecks. For example, the *region* Denmark has two *areas* in this study.

national statistics of the respective Nordic country [16,17,42,43]. Figure 3 depicts the installed power production capacity in the Nordic countries at the end of 2013.

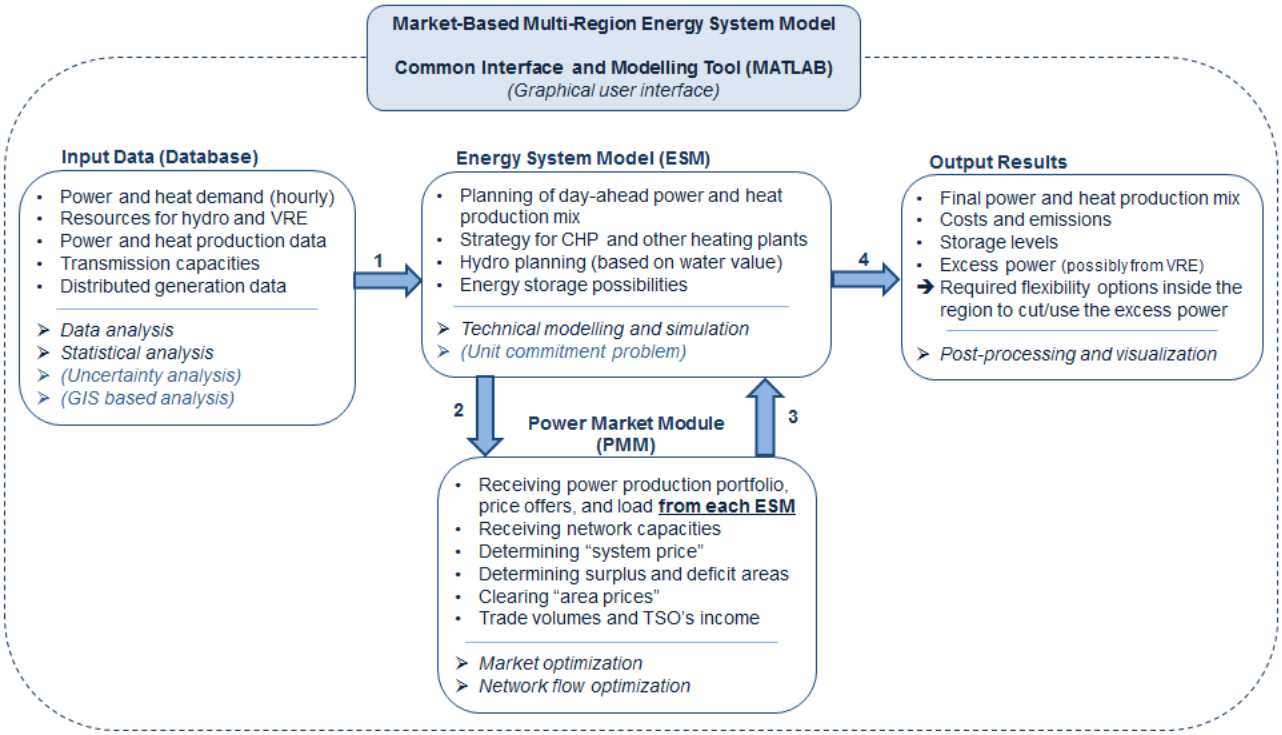


Figure 2. Outline of the market-based multi-region energy system model (multi-ESM) presented in this study. The main procedure in each section of the model is highlighted with dot bullets. The analytical approach or method used in each section is shown at the bottom of the respective box with arrow bullets (those approaches in parentheses are under development and not implemented in this study).

The hourly availability of wind resources and sun radiation for solar PV plants are based on the available production data for Denmark and Sweden, while modelled for Finland based on [44]. The water flow resources for hydropower are also obtained based on the weekly data available in [39]. The capacity of CHP plants in district heating is specified for each ESM with their fuel mix.

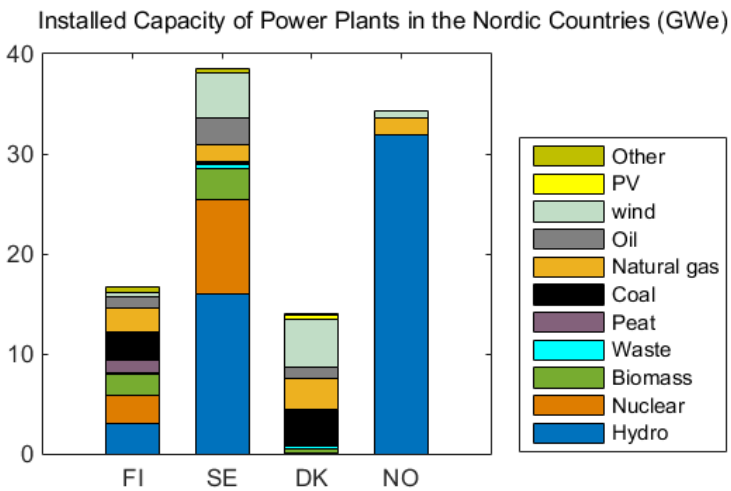


Figure 3. Power production capacity in the Nordic countries at the end of 2013 (FI: Finland, SE: Sweden, DK: Denmark, NO: Norway)

In order to define the corresponding heat demand in each region, we apply the concept of heating degree days (HDD). Based on the guidelines provided by Statistics Finland, the heat demand is

calculated for an indoor comfort temperature of 17°C. The HDD are determined based on the hourly averaged ambient temperatures obtained for the capital of each country. The variable costs of the power plants and fuel prices are based on national statistics and [12,45]. Average carbon price of 8 €/t is used for the calculation of fossil fuel-based generation costs. Table A 1 in Appendix A illustrates the details of input data of power and heat sectors in the year 2013 for each Nordic country. The input data can be collected in the database and continuously maintained for the future studies.

2.1.2. Energy System Model (ESM)

As discussed earlier, an ESM model represents different sectors of the energy system inside each country. In this contribution, the creation of individual ESMs resembles the procedure applied in present modelling tools used for the detailed analysis of national/regional energy systems, for example EnergyPLAN [46]. For the case study examined in this contribution, we model the main structure of the existing energy systems. However, the user might examine the structural changes in the energy infrastructure for other cases, e.g., by smart electrification of transport or new methods in modelling of flexible demand. Figure 4 illustrates the main building blocks of each ESM (i.e., bidding area) examined in this study. The interconnection of heat and power sectors in today's energy systems can be evidently seen in different ways.

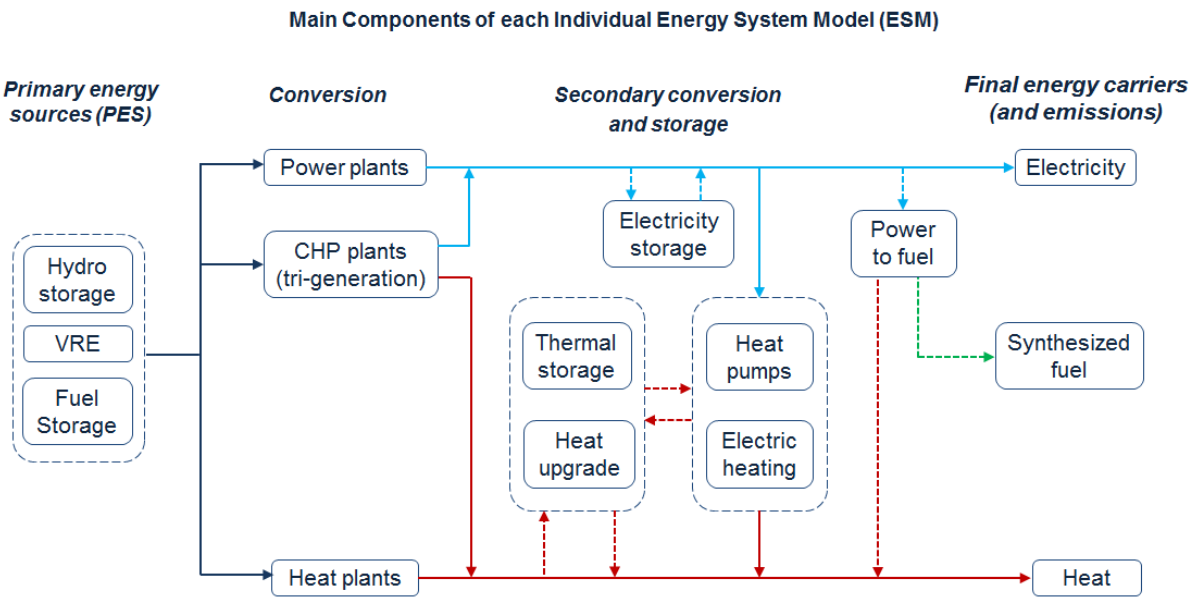


Figure 4. A schematic presentation of each individual energy system model (ESM) and their main components and energy streams (stream colour indicator: PES (black), electricity (blue), heat (red), synthesized fuel (green), and the streams that are not necessarily present in the examined scenarios are dashed.)

To initiate the modelling, we employs hourly data of the day-ahead energy demand (based on historical data or forecasted) to propose the most cost-efficient heat and power production mix, with the priority given to VRE. For each area (i) in each hour of the year (h), the heat demand (q) is met by onsite heat supply (t^{os}) plus DH supply (t^{dh}), as stated in Eq. (1) in an aggregate way[2].

$$\forall i, h \qquad q_{i,h} = t_{i,h}^{os} + t_{i,h}^{dh} \qquad (1)$$

[2] Each heat or power supply group comprises a set of technologies and fuel types that are not expanded in the equations for the sake of convenient readability. For example, one may expand DH supply as $t^{dh} = \sum_x t^{dh,x}$, in which x is different fuel types.

For each heat supply mode (either onsite or DH), the hourly heat supply comprises generation and harvest from available stored heat, see Eq. (2).

$$\forall i, h \qquad t_{i,h} = gen_{i,h} + stor_{i,h} \qquad (2)$$

DH generation originates from two main groups of plants: heat-only production modes ($gen^{dh,ho}$) such as boilers and solar-assisted DH collectors, as well as heat from multi-generation plants such as CHP ($gen^{dh,chp}$), as suggested in Eq. (3):

$$\forall i, h \qquad gen_{i,h}^{dh} = gen_{i,h}^{dh,ho} + gen_{i,h}^{dh,chp} \qquad (3)$$

For those cogeneration plants without an additional steam condenser, power generation from CHP plants ($gen^{el,chp}$) is a function of the respective heat generation (see Eq. (4)). In this study, this function is modelled as an average power-to-heat coefficient (usually 0.5) representing all the CHP technologies across each region *i*.

$$\forall i, h \qquad gen_{i,h}^{el,chp} = f\left(gen_{i,h}^{dh,chp}\right) \qquad (4)$$

Therefore, the determined power production from CHP will be placed in the initial power production portfolio, to be sent to the pool together with other power-only plants. The associated marginal cost for power from CHP is determined after deduction of income from the respective DH generation (based on DH prices). However, the final power production mix is not decided merely inside the region, as the power prices may necessitate import or export of power in particular hours. The proposed power production mix will be sent to the common power market, and the outcome of the market (prices and trade volumes) defines that which production units will be operating the following day. Then, the heat and power production inside each region will be finalized, accordingly. As a result of power market optimization, the electricity price is indigenous in the proposed model, which reflects the dynamics of the whole multi-region energy system.

Figure 5 reveals how the market prices can be affected by the operation of CHP plants (and vice versa). CHP plants are compensated from heat and power sales, hence, offering lower prices to the pool compared with their counterparts that are solely producing power. In hours with low prices in the market, some more expensive CHP plants may be shut down. Consequently, the heat supply mix will experience a different production portfolio compared to the case without trading on the power market. The optimal operation strategy of CHP plants in liberalized power markets for ensuring the minimum cost for the system, and to maximize the profits for the plant owner have been studied in [47] and [48,49], respectively.

2.1.3. Power Market Module (PMM)

The PMM interconnects individual ESMs through a common market (pool) and a network of power transmission lines. The power market modelling has been widely studied in the past, with different analytical approaches, e.g., data mining for multi-agent models [50], game theory models [51], fuzzy Q-learning methods for agent-based models [52], and partial equilibrium models [53]. For instance, Hargreaves and Hobbs [54] suggest multivariate adaptive regression splines to use the recorded data to make predictions of the outputs by employing a large-scale linear program to simulate the US power market.

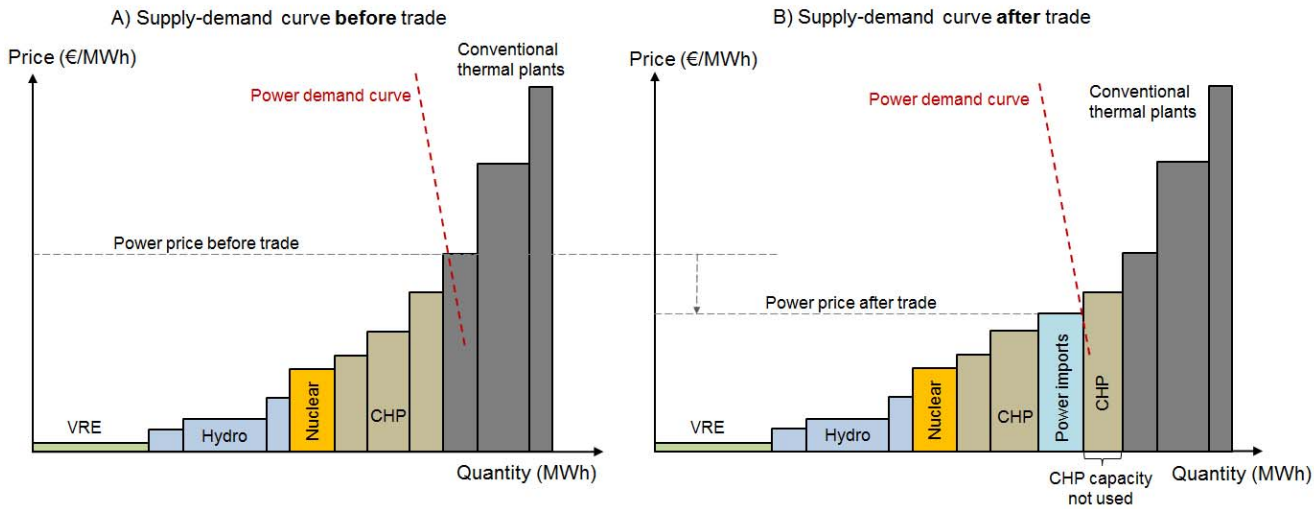


Figure 5. The operation of CHP plants in liberalized power markets based on the governing electricity prices. The case without considering the power prices (A) is compared with a case after the settlement of market price (B)

The aim of PMM in our model is not to predict the real-time (short-term) prices of electricity, but to represent a near-reality medium- to long-term pattern of electricity prices in the market. We propose a social welfare maximization approach explained in Eq. 1, in which n is the number of interconnected regions. In Eq. (5), i represents a price area, d_i is electricity demand in area i, and D_i is the price dependant electricity demand curve in the respective area, while s_i represents power supply in area i and S_i is the price dependant power supply curve in the same area. The procedure is adopted from the algorithm applied in Nord Pool Spot [55]. In this study, we do not consider block orders, as we do not apply unit commitment modelling either.

$$\max \sum_n \left(\int_0^{d_i} D_i(x)dx - \int_0^{s_i} S_i(y)dy \right) \qquad (5)$$

Eq. (5) ensures that the difference of consumer's utility and producer's production costs is maximized in the whole Nordic region (not just in favour of one or some countries). This is based on the assumption of perfect competition and the neutrality of the TSOs and the market operator. For example, if the area price in Sweden would be lower than Denmark and Finland, and the surplus electricity would be limited, the electricity flows to the area that has higher prices. The objective function (Eq. (5)) is subject to the following constraints:

In each area, the energy balance must be respected; demand (d_i) is equal to the sum of power supply (s_i) and the sum of net imported electricity. In Eq. (6), the value e_{ji} stands for the exchange of electricity from region j to i, while e_{ik} denotes the flow from i to k.

$$\forall i, h \qquad d_{i,h} + \sum_k e_{ik,h} - s_{i,h} - \sum_j e_{ji,h} = 0 \qquad (6)$$

The maximum transmission capacity (T^{max}) defines the maximum exchange between two connected areas (Eq. (7)):

$$\forall i, j, h \qquad 0 \leq e_{ij,h} \leq T_{ij,h}^{max} \qquad (7)$$

The electricity cannot flow in both directions in a transmission line, as Eq. (8):

$$\forall i,j,h \qquad 0 < e_{ij,h} \leftrightarrow e_{ji,h} = 0 \tag{8}$$

If the spot prices differ between two bidding areas, then the transmission capacity between these areas should be fully employed towards the area with the higher price. If the transmission capacity between two areas is not fully utilized, the prices in these two areas shall be equal, as stated in Eq. (9); in which $p_{i,h}$ shows the electricity price in area *i* at hour *h*.

$$\forall i,j,h \qquad 0 \leq e_{ij,h} < T_{ij,h}^{max} \leftrightarrow p_{i,h} = p_{j,h} \tag{9a}$$

$$\forall i,j,h \qquad e_{ij,h} = T_{ij,h}^{max} \leftrightarrow p_{i,h} < p_{j,h} \tag{9b}$$

The prices in two sides of a transmission link are equal to the system price as far as the respective transmission capacity is not fully used. In case of congestion, the area prices may differ, and the congestion income is equally shared between the two respective TSOs. Moreover, the PMM guarantees that all the supply bids with lower prices than the system price would be accepted, and the accepted supply never exceeds the maximum capacity of the respective producer. The market is modelled based on marginal cost[3] of the producing plants.

To solve the problem, we apply a branch-and-bound technique to segment the problem into several steps and solve it by applying the following procedure:

1. In addition to the power demand (which is inelastic in this study), the primary power production portfolio (supply curve) of the following day from each area is sent to the pool (for the bidding strategy of hydropower plants see Section 2.1.5)

2. The PMM determines the system price for each hour of the day ahead by intersection of the aggregated supply and demand curves of all areas.

3. After determining the system price, the maximum supply by this price in each area is calculated. The surplus and deficit areas will be determined with the amount of surplus or deficiency, respectively.

4. The network capacity is employed to establish the optimal power flow so that the requirements of the Eq. (1) and its constraints would be met (see Section 2.1.4 for the power network).

5. After clearing the system and area prices, the congested lines will be specified and the congestion income will be calculated.

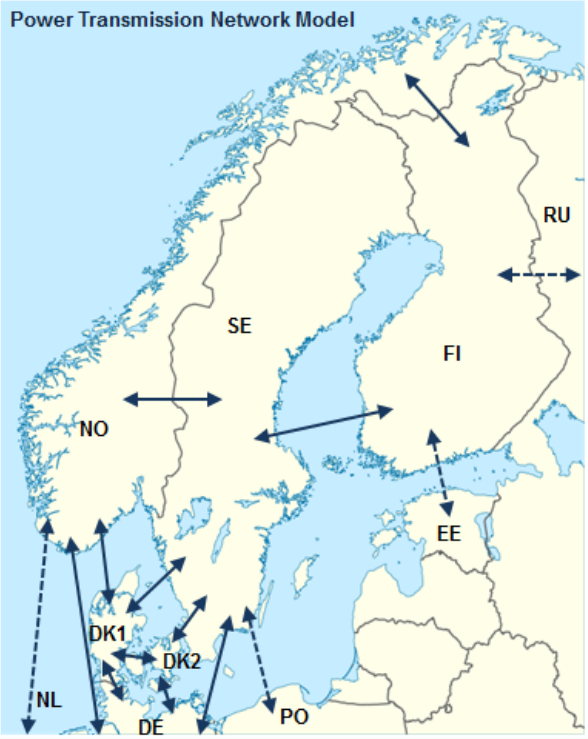
6. The final accepted producers' bids as well as the amount of power exchange in each line will be reported to each ESM, so that they plan the power (and heat) production mix of the day ahead.

2.1.4 Power Transmission Network

The transmission network modelled in this study and the respective capacities in two directions are illustrated in Figure 6. We consider Sweden and Norway as one price area each, while

[3] The general marginal costs of power production considered in this study include, biomass 28-40, coal 40-65, natural gas 55-80, heavy fuel oil 85-110, and nuclear fuel 10-18 €/MWh$_e$, based on [12,17,42,43,45].

Denmark is modelled as two price areas[4]. Hence, the transmission links of Sweden-Norway and Sweden-Finland are modelled as one aggregate link, respectively.



Line	Maximum capacity	
	From-to	To-from
NO-FI	90	90
NO-SE	3695	3995
NO-DK1	1632	1632
NO-NL	700	700
SE-FI	2700	2300
SE-DK1	680	740
SE-DK2	1300	1700
SE-PO	600	600
SE-DE	615	615
FI-RU	320	1460
FI-EE	1000	1000
DK1-DE	1780	1500
DK2-DE	585	600
(NO-DE)	(1400)	(1400)

Figure 6. Power network transmission lines modelled in this study, as well as the maximum capacity of each line in each direction (based on the data from Nord Pool). Note: the dashed lines are modelled with the same trade volume as 2013.

2.1.5. Simulation of Hydropower Production

The Nordic power market is a market dominated by hydropower. The price of electricity therefore is highly dependent on the precipitation situation in the examined period. The analysis and simulation of hydropower plants in a wide region like the Nordics is a complicated task. The hydro producers in countries like Norway apply regional optimization strategies to ensure the maximum harvest from common resources (e.g., several dams on one river), while keeping the strategic reserves at an acceptable level.

The reservoir level itself is a function of time of the year (see Figure 7). To represent the aggregate behaviour of hydro producer in each area, we employ the concept of *value of water*[5]. The hydro producers adopt a strategy to maximize their income against the possible loss of income in the future. Wolfgang et al. [56] proposes a dynamic stochastic programming to model the water value of hydro in Norway. They estimate the expected marginal value of keeping more water resources for the next days to quantify the optimal amount of water for the present week. We apply a deterministic, simulation-based water value strategy to estimate the real life aggregate behaviour of hydro producers. We consider the hydro inflow for each week, for each country (Norway, Finland, and Sweden) to simulate the hydro production in each country separately, subject to the maximum capacity of the reservoirs and the maximum power output of the hydro turbines. Therefore, water spillage (curtailment) will be minimized and the water value is indicatively determined as a function of the reservoir level (see [57,58]).

[4] The reason for such an assumption is that the area prices in Sweden have been equal during more than 90% of the time in 2013. Denmark is modelled as two price areas since the main goal of this study is to see the impact of the Energy Transition in Germany on the Nordic countries, and Denmark areas are critical corridors in this respect.

[5] The *water value* is the expected marginal value of the energy stored in the reservoir.

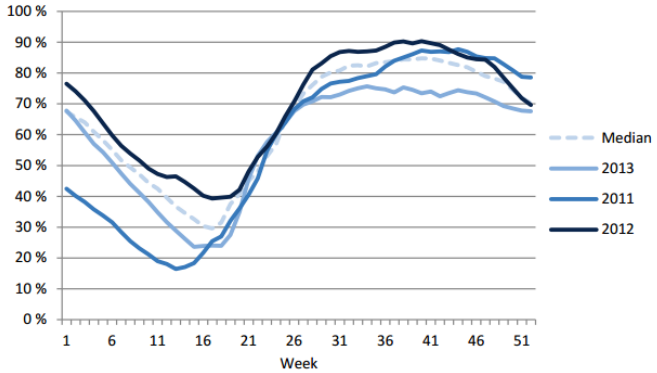


Figure 7. Hydro reservoir level in the Nordic region 2011-2013 (source: [59])

2.2. Validation of the Model and Its Limitations

The simultaneous modelling of four countries' energy systems is complex and cumbersome. The countries might introduce different energy taxes and fuel prices, which possibly results in different marginal costs for production. The hydro modelling itself is a main challenge. To monitor that if the proposed model has captured the main dynamics of the Nordic power market, we compare the outcome of the model for a benchmark year (2013) with the recorded statistics of the same year (see Appendix A for the input data to the model). The advantage of the proposed model is that power prices are outcome of the model and they can be validated by already recorded statistics on an hourly basis. This comparison can be made, first, based on the yearly average values, and followed by more refined time resolution. The comparison of the average system price and area prices illustrates the possible gap between the initial input data for marginal cost of technologies and the real time power prices. Then, by employing a step-by-step iterative method, input marginal costs of production plants are adjusted for each bidding area, which also changes the system and area prices. This procedure continues to approach the recorded prices with a reasonable difference in averaged values, as the model does not approach the electricity prices in all hours of the year in all the bidding areas.

The results indicate that the yearly prices converge to the historical statistics by a relative error of less than 3%, seasonal values 1-6%, and monthly values 2-11%. Figure 8 depicts a sample comparison of the hourly results with the recorded statistics for the hourly system prices in 3 weeks in 2013. The hourly comparison reveals that the model is not capable – and is not designated so – to capture those instantaneous (unpredicted) changes in real time prices. The high jumps in electricity prices are not correctly seen in the results. These deviations are due to different reasons. First, we model and optimize the market based on the assumption of perfect competition based on short-term marginal costs of the technologies, while some producers apply strategic (long-term) bidding in real life. We are not properly aware of the algorithm used by hydro producers for optimizing their revenues. The model does not predict unexpected losses of power production or transmission capacity in real life. We may overestimate the installed capacity of power production units in the model (lack of detail knowledge about operating plants in each season in each country). It is worth to remind that the model proposed in this study is not suitable for bidding in the market, and is a part of medium- to long-term energy system planning. However, the second source of errors that are shown in Figure 8 relates to the limitation and drawbacks in the modelling approach that can be improved by collecting more statistical data to adopt a more realistic marginal cost for different technologies in different countries. These improvements will be gradually confirmed and applied in the future studies.

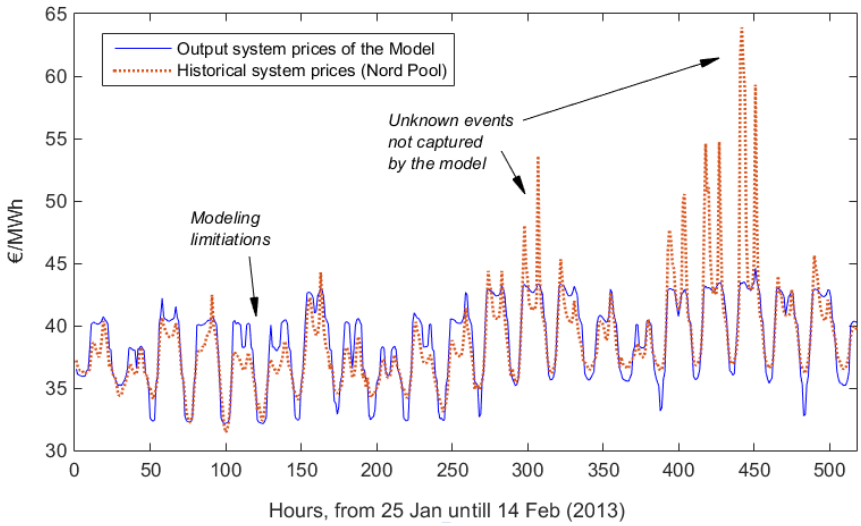


Figure 8. Comparing a sample of the model outputs with the available statistics – two sources of errors are highlighted.

3. Energy Transition in Germany

The term *Energiewende* (Energy transition) refers to a set of energy policies adopted in Germany for boosting energy efficiency and the use of renewable energy. The final target is to step in a road for shaving the use of fossil and nuclear fuels. Wind power and solar photovoltaic (PV) have been two major pillars of this transition, supplying more than half of all renewable energy in Germany in 2014 [60].

The German power market is highly connected to the neighbouring countries, including the Nordics. This has led to variations in flow of power to the neighbouring markets in periods of high VRE in Germany, and vice versa. Since the transmission system in Germany experiences a north-south bottleneck, various alternatives have been long considered to balance VRE production outside of Germany, including through Nordic hydro storage reservoirs. The exchange has so far been done through the links to Sweden, West and East Denmark, and indirectly via Poland and the Netherlands. There are however new plans for the expansion of interconnectors to Norway, through NordLink, for example. In this respect, the construction of NordLink – a 1400 MW, 500 km, HVDC line – was initiated in 2014, which connects Ertsmyra in Norway to Schleswig-Holstein in Germany [61]. The initial cost estimations are around 1.5-2 b€ for delivering the project by 2018.

The Energy Transition and its impact on the Nordic power market is an important topic, from technical and balancing issues to economic and market-related signals. The issue of investment on new power generation capacity requires careful attention not only to the internal changes of the market, but also to the waves of VRE imported through further market couplings. The impact of electricity prices on consumers and producers are significant, which calls for informed regulation strategies to guarantee the success of such market couplings [62]. While some studies have seen this impact as a new opportunity for (at least) Nordic hydro producers [14], the general picture of this impact is not yet analyzed in an adequate detail. This study addresses this gap by providing a dynamic evaluation of this impact on all the four Nordic countries, and on all the market participants (consumers, producers, and grid operators).

Since the beginning of the Energy Transition, the average power prices have been decreased in Germany, while the price volatility is ever growing. In a detailed analysis of German power prices during 2006-2012, Ketterer [63] employs a GARCH model and illustrates that the price volatility has been increasing as a result of higher wind integration. They consider the impact of weather conditions, nuclear production, new regulations in the market[6], as well as market couplings, which increases the credibility of the results. We employ the same strategy in this contribution to reflect the changes in future electricity prices in Germany. Therefore, we calculate the relative growth in the installed capacity of wind and solar PV from 2013 through 2020. We simulate the increase in the price volatility relative to the growth ratio in the installed capacity of VRE (from reference price volatility for 2013). This approach entails the following assumptions: (i) the pricing mechanism in the market will not change in the time frame of this analysis (marginal cost based remains valid), and (ii) the price variations in Germany will directly reflect on the power flow coming to the Nordics (we do not study the dynamics of other markets connected to Germany).

Table 1 summarizes the future scenarios examined in this study including the associated assumptions. In Case 1, the planned VRE in Germany is assumed to be installed and become operational, without further changes in the other countries. In Case 2, the NordLink (1400 MW transmission line) is added to the existing transmission network, while all other parameters remain fixed.

Table 1. Installed capacity of VRE in future energy scenarios

		Future scenarios		
	year 2013	Case 1	Case 2	Case 3
Wind, DE (GW)	34.6	53	53	53
Solar PV, DE (GW)	36.3	52	52	52
Power from VRE, DE	18%	25%	25%	25%
NordLink (GW)	0	Not built yet	1.4	1.4
VRES in the Nordics	Today	As today	As today	2020 plans

In the first two cases, the pure impact of the Energy Transition in Germany can be studied without varying any parameters inside the Nordic region. However, in Case 3 the projected changes in the Nordic countries are also taken into account to see the result of the all VRE plans in the region. These changes in the Nordic countries' VRE capacity is depicted in Table B 1, in Appendix B.

4. Results and Discussion

4.1. Impact on Power Flow and Prices

By employing the methodology applied in this study, we examine the impact of future VRE installations in Germany on the Nordic power market. Since the respective markets are coupled, we assume that electricity can be freely traded between the two markets, subject to availability of demand/supply in the Nordics, as well as power transmission constraints. We set the maximum transmission capacity of each line as a virtual demand/supply for Germany in each particular hour. When the prices in Germany are lower than the Nordic power market, electricity is

[6] The German regulator amended the market regulations of VRE electricity in January 2010. All TSOs are now required to forecast the VRE production one day ahead, and to sell the total forecasted value on the day-ahead market. TSOs are compensated from selling the renewable power at the price of wholesale market.

imported from Germany (and we assume there is enough supply in Germany). While we only model the reflection of Germany's electricity prices on the connecting corridors (without modelling Germany itself), the Nordic power market is dynamically simulated and changes are applied hour by hour. Figure 9 illustrates the price areas modelled in this study and the interconnecting transmission lines. The left map shows an exemplary case in which the electricity price in Germany is lower than the Nordic system price. The power flows from west Denmark (DK1), east Denmark (DK2), and Sweden (SE) to the deficit areas in the Nordics. As a result of these exchanges the system price stands in 30.6 €/MWh in the Nordic power market.

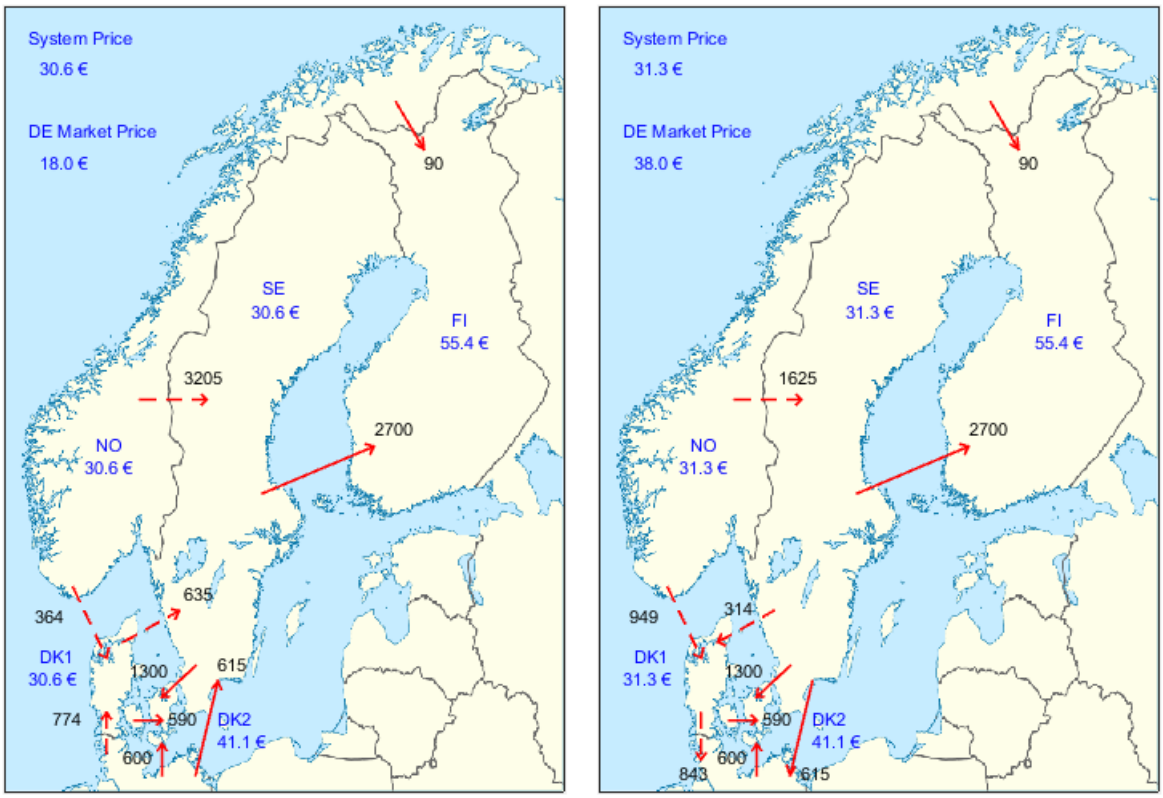


Figure 9. Impact of Germany's power prices on the Nordic prices simulated in this contribution for two different states: when the Germany's price is lower than the Nordic system price (left figure) and when the Nordic is lower (right figure). The area prices are labelled on each area (or country), and the traded volumes (MWh/h) are shown near each line. The non-congested lines are highlighted with dashed arrows while congested links are continuous lines.

In Figure 9 (right), the Germany's price is higher than the system price in the Nordics. While the flow of power diverts to north-south, DK2 is still profiting from the cheaper price in Germany. The Nordic system price is 0.7 €/MWh higher than in the previous case (left), while all the parameters except of electricity price in Germany are identical. For this example, there is no impact on the Finnish area (FI), as the area is already in high deficiency and power transmission lines from SE (and NO) are fully congested. However, the significant change in import from NO to SE reflects internal dynamics of the Nordic power market in response to the new changes. The congested power lines are distinguished with continuous lines, compared with dashed lines for the non-congested lines. It should be noted that other external transmission lines not shown in Figure 9 are simulated in the model based on the 2013 data.

4.2. Impact of NordLink (Case 2)

In Case 2, the pure impact of NordLink is examined by keeping other parameters unchanged. The results will provide information on social benefits of market couplings and the estimation of return on investment on transmission lines, for example. By applying the same procedure

explained in the previous Section, we model the commissioning of this new transmission line for a period of a whole year (8760 h). The results are presented in Figure 10, by showing the yearly average prices on each area, followed by 2013 values in parentheses. The results indicate an increase in the average system price, and area prices in most of the Nordic areas. In other words, while the average price of electricity in Germany declines as a result of higher VRE, this reduction is not directly reflected on the Nordic power market. The reason for this is that in many cases the price of electricity is extremely low in Germany, at times when the prices are low in the Nordics too (as a result of high wind production in a close geographical area, for example).

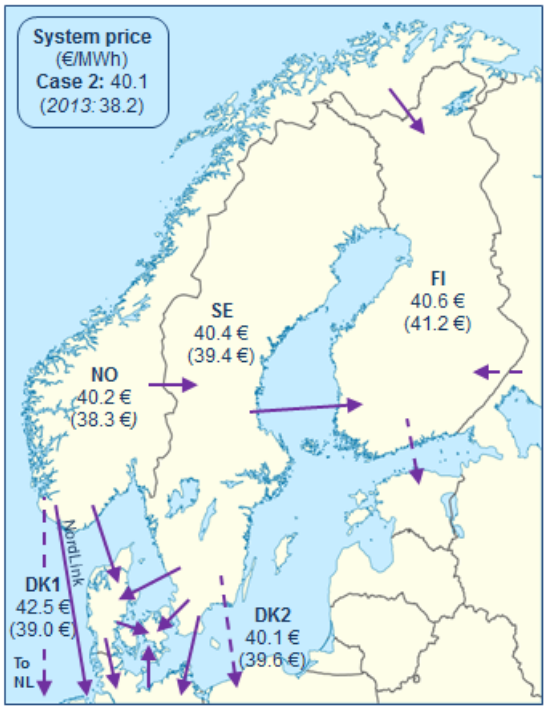


Figure 10. Status of the Nordic power market in Case 2 (after commissioning of NordLink). The direction of arrows illustrates the dominating transmission direction in that line over the whole year. Dashed lines are simulated with the same trade volume as 2013 (static modelling). The yearly average electricity prices are labelled on each region (2013 prices shown in brackets).

Limited transmission capacity is the other observed reason for this disability of the Nordic power market to benefit from extremely low prices in Germany. This implies that one should not investigate the impacts of market couplings only by considering average electricity prices in the connecting markets. The more informed analysis should address the dynamics of the system from hour to hour. On the other hand, when the prices are high in Germany, the Nordic power market – which is a hydro dominant power market – has enough capability to sell power up to the transmission limits. This will naturally lead to higher prices in the Nordic region itself. The dominant direction of power flow in the existing transmission lines and NordLink (illustrated in Figure 10) confirms the previous findings: the power flows mainly from the north to Germany. It should be noted that those transmission lines to the external markets that are dashed in Figure 10 are not simulated dynamically in this analysis, and the trade volumes are the same as for 2013.

Congestion rent is one of the revenue sources for the TSOs who invest in new transmission lines. Our analysis demonstrates different congestion times in the lines between Germany and the Nordics in Case 2. The simulation results show that after the operation of NordLink, this line will be possibly near-fully in use around 80% of the hours a year. In the same period, the DK1-DE line may be congested only half of the time in a year. This may reveal the advantage of direct

trade between NO-DE in high VRE scenarios, compared with the existing indirect routes. Considering the transmission capacity of 1630 MW for NO-DK1, compared to 1700 MW from DK1 to DE is the first reason. Moreover, the wind-thermal power production mix in DK is highly similar to DE, which may compete in harvesting cheap hydro in periods of low VRE (or exporting extra VRE to NO). Table 2 presents the congestion time and the associated income for the lines between Germany and the Nordic power market. The direction of each line (from-to) shows the dominating direction in the respective simulation year.

Table 2. Congestion time and the related revenues on transmission lines between Germany (DE) and the Nordics in Case 2, after the commissioning of NordLink. The dominating direction is also shown by the abbreviations.

Line (from-to)	Congestion time (% from the whole year)	Congestion income (million euro)
DK1-DE	52%	158
DE-DK2 (Kontek)	39%	38
SE-DE (Baltic Cable)	81%	130
NO-DE (NordLink)	84%	286

4.3. Impact on Market Participants

Any future transition in the power market may influence the market participants (consumers and producers) through different ways. While wholesale electricity prices are not necessarily identical to those of retail markets, they are the main indicators of the efficiency of adopted policies in the examined market. It is argued that market couplings will pave the way for higher EU-wide integration of VRE and a cleaner Europe, as well as less stress on the electricity grids in the events of high VRE [64].

To monitor the impact of the Energy Transition in Germany on the main actors of the Nordic market, we compare their future situation with 2013. For example, for electricity consumers, we determine their yearly surplus for the market conditions in 2013, and then we compare this amount with their surplus in the future transitions. The initial results demonstrate that consumers in most of the Nordic countries lose a share of their surplus in the future transitions. In other words, the Energy Transition in Germany will increase the electricity prices in the Nordic region leading to higher payments by local consumers: higher electricity prices for the same consumption amount means depreciating the consumer surplus. Oppositely, the produces in the Nordic region improve their surplus. They will find a new market for their product with slightly higher prices. Moreover, when the electricity price inside the region grows, producers collect greater revenues for delivering the same amount of electricity. Figure 11 demonstrates these changes in different scenarios examined in this study and for different countries.

As the results suggest, the magnitude and type of the impact is not identical in the Nordic countries. For example, the Danish consumers will probably pay the highest increase in electricity prices after the energy transitions. This might be due to different reasons. A country like Denmark is highly correlated to Germany with respect to the VRE resources (wind and solar PV here). Therefore, higher market couplings do not introduce lower electricity prices in Denmark, as very low-price periods in Germany overlap with relatively low-price hours in Denmark, diminishing the potential for harvesting cheap electricity.

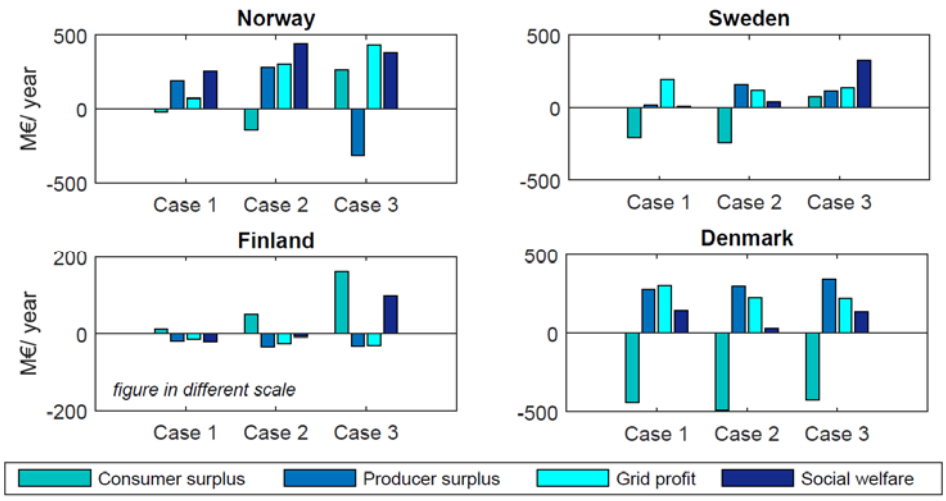


Figure 11. Impact of future energy transitions on different stakeholders in the Nordic countries compared to 2013 (the values are relative to 2013)

When the prices are high in Germany (as a result of high demand and scarcity of VRE in particular hours), the market coupling increases the price in the Nordic system, and consequently in Denmark. Therefore, the consumers have to pay higher prices compared to the time before the market coupling. Oppositely, the Danish producers gain much higher revenues after the market couplings, as they profit from higher prices and more consumers. However, looking at the gain and loss reveals that the revenue recovery by producers is yet much lower than the loss of consumers in Denmark. For example in Case 2, it can be seen that the revenues have shifted to other countries like Norway (mainly as a result of the new link). The improvement in the surplus of producers is not evenly distributed.

The other important implication of market coupling lies in the revenues gained by grid operators. TSOs invest on the expansion and reliability of the grid, and they divide the congestion income. The study of grid owners' income shows that they receive higher revenues after the market couplings, in most of the cases. This is partly due to a greater trade volume and the direct income from the bottleneck events. The dynamics of the prices are also important in this respect: the higher the price difference between two regions connected by a congested line, the greater congestion income for the grid operators. This situation introduces opportunities for countries that are situated in the transmission corridors, like Denmark. In the study of competitive power markets, the term *social welfare* is widely used as an indicator to evaluate the performance of a market. The social welfare is the sum of the three mentioned revenue streams: the consumer surplus, the producer surplus, and the grid owner's income [62]. The results suggest that the social welfare may improve in all the Nordic countries except Finland, after the Energy Transition in Germany (Figure 11). For example, in Norway and in Case 2, the recovered social welfare may reach half a billion euro per year.

5. Conclusions

The study of the impact of electricity market couplings and the expansion of power markets to areas with different load and production pattern is a complex task. In this study, we proposed a new multi-region energy system model (multi-ESM) to analyze the dynamics of the Nordic power market under future planned scenarios for power exchange with Germany (as a part of the NWE power market). The results indicate that the Energy Transition in Germany might entail significant and different impacts on the Nordic countries. The consumers' benefits are tightly

associated with the price variation patterns and the pricing mechanism. We assume the Energy Transition in Germany continues to decrease the wholesale electricity prices in the German power market, while intensifying the price volatility. However, this reduction in average prices in Germany does not lead to lower prices in the Nordic region, and prices even increase in some cases. It is not possible to fully profit from electricity trade in events of very low prices in Germany, as the VRE production in the connecting areas is correlated, leading to low prices in the Nordics as well. Oppositely, high price hours in Germany (high demand and low VRE production) will directly impact the prices in the Nordics as a result of an additional power demand that must be met with higher-cost generating plants.

Despite of the possible loss experienced by the Nordic consumers due to increased power prices, the producers may improve their surplus from further market couplings. This is due to higher electricity prices in the market, which shifts the consumer surplus to the producers. The revenues gained by the Nordic producers are not, however, corresponding to the loss of consumers in the respective country. Further market couplings and the growth in power exchange in countries with different production/consumption patterns (e.g., Norway and Germany through NordLink) will lead to a greater grid congestion income in most of the examined cases in this study. The numeric values calculated in this study can inform the policy makers and grid owners on the benefits of transmission expansion versus domestic flexibility measures, such as power to heat or power to gas.

The Energy Transition in Germany improves the net social welfare in the Nordic countries (except Finland). It means the surplus gained by producers plus grid owners' congestion income surpasses the loss of consumers. This necessitates an efficient regulatory framework for allocating revenues and to cope with the respective economic consequences for the consumers.
The results of this study reveal the need for detailed analysis of the market couplings through a market-based, multi-region energy system model. When interpreting results, the focus should not be only dedicated to the average values, as the patterns in different times of the year might result in different outcome. Future work will focus on collecting more details of the production fleet and price areas of the Nordic region, as well as a more robust methodology in determining the magnitude of price volatility in the external power markets.

Acknowledgements

The authors appreciate funds and supports provided by Aalto University's Energy Efficiency research program and STEEM project (Sustainable Transition of European Energy Markets). We sincerely thank the following researchers for their comments on this study, Vilma Virasjoki, Matti Koivisto, John Millar (Aalto University), and Nina Juul (DTU, Denmark). We demonstrate our appreciations for the input time series data supported by Paul-Frederik Bach through his dedicated webpage. The first author thanks the EnergyPLAN development team at Aalborg University, Denmark, for providing the initial energy system models of Denmark, Norway, and Sweden through their dedicated webpage, and for other supports throughout this study.

Appendix

A. Energy Demand and Production Capacities

Table A 1. Annual demand of heat (onsite and DH) and electricity, as well as production capacities in each bidding area

	Unit	NO	SE	DK1	DK2	FI
Electricity demand	TWh/a	128.7	137.8	20.5	13.5	85.1
Onsite (individual houses) heat generation						
Individual HP	TWh/a	0.2	2.3		1.3	4.2
Electric heating	TWh/a	38.7	20.1		-	14.2
Boilers	TWh/a	10.2	23.7		21.6	12.8
Total	TWh/a	49.1	45.1		22.9	31.2
District heating (DH)						
DH demand	TWh/a	2.2	58.5	20.9	18.9	36.7
Heat-only boilers	TWh/a	0.3	15	2.8	2.7	10.3
Decentralized CHP	TWh/a	-	11.5	5.4	5.2	13.8
Centralized CHP	TWh/a	1.9	32	12.7		12.7
Power Generation Capacity						
Wind power	MWe	820	4425	3790	1032	450
Solar PV	MWe	10	45	420	178	10
Hydropower	MWe	31900	15950	0	0	2550
Nuclear power	MWe	0	9530	0	0	2780
Large-scale HP	MWe	-	150	5	-	33
Decentralized CHP-DH	MWe	-	590	790	945	2150
Centralized CHP-DH	MWe	110	3080	1715	1010	1350
CHP industry	TWhe/a	1.6	5.6	0.3	0.3	8.3
Condensing plants	MWe	1600	4780	2420	2360	3500
Other information						
Hydro reservoir	TWh	84.3	33.7	0	0	4
Power to heat ratio CHP	-	0.5-0.6	0.5-0.6	0.5-0.6	0.5-0.6	0.5-0.6
Average COP for HP	-	3	3	3	3	3

B. Transition in Installed Capacity of VRE in the Nordic Countries

Table B 1. Installed capacity of VRE in the Nordic countries in Case 3 (around 2020)

	Unit	NO	SE	DK1	DK2	FI
Wind power	MWe	2000	6730	4710	2040	1900
Solar PV	MWe	20	250	840	360	25

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